**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Application of Pacific Gas and Electric Company To Revise Its Electric Marginal Costs, Revenue Allocation, and Rate Design. (U 39M)	Application No. 06-03-005 (Filed March 2, 2006)

COMMENTS OF PACIFIC GAS AND ELECTRIC COMPANY ON QUESTIONS RAISED IN THE AUGUST 22, 2007, SUPPLEMENTAL SCOPING MEMO AND ASSIGNED COMMISSIONER'S RULING

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Dated: October 5, 2007

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Pursuant to the August 22, 2007, Supplemental Scoping Memo and Assigned Commissioner's Ruling in Phase 2 of Pacific Gas and Electric Company's (PG&E) 2007 General Rate Case (GRC), PG&E hereby submits comments on questions the Commission has raised regarding dynamic pricing. The comments themselves are attached to this pleading.

PG&E emphasizes the following basic points in its comments:

- The Commission should preserve customer choice and avoid mandatory tariffs as it develops new rate options;
- PG&E is making good progress in developing new tariffs and recruiting customers for its existing portfolio of voluntary programs; and
- The Commission should defer action on developing real-time pricing (RTP) tariffs until after Market Redesign and Technology Update (MRTU) prices are available and the parties have some experience working with them.

Following is a brief summary of PG&E's general approach to each of the 12 subject matter areas about which the Commission has inquired:

Section I: Objectives of dynamic pricing and time-differentiated rates

The Commission should adopt clearly defined and narrowly stated policy goals for its dynamic pricing investigation, and should limit the scope of this investigation to the generation component of retail tariffs and to the rates paid by bundled service customers. Thus, direct access (DA) and community choice aggregation (CCA) customer rates would be outside the scope of this proceeding.

Section II: Rate options

The Commission should develop new dynamic pricing options and demand response programs while preserving customer choice, and should focus on those rate classes, customer groups and end uses that offer the greatest potential for producing significant new sources of demand reduction.

Section III: Components of dynamic pricing tariffs

Visible forward market prices from the MRTU are not yet available, and even after MRTU implementation it may take some time to determine the suitability of MRTU prices for ratemaking purposes.

Section IV: Recovering the revenue requirement

Costs and revenues should be reasonably well correlated if well-designed and cost-based dynamic tariffs are adopted. Revenue under-collections that might result from lower than expected sales should be partially offset by lower procurement costs relative to the original forecast used to set rates. Conversely, if electricity usage is higher than expected, the resulting incremental procurement costs would tend to approximately match incremental revenue.

Section V: Hedging

A system of voluntary participation credits (paid by small premiums attached to the rates paid by non-participants) can serve the same purpose as applying explicit hedge premiums to non-participant's rates. PG&E cautions that hedge premiums may be used differently depending on the context, and it is not clear that there is yet a solid foundation for applying hedges to dynamic pricing options.

Section VI: Sources of triggers and prices for dynamic pricing

Most dynamic pricing triggers and demand response program operations should be activated and communicated to customers by the utility, acting in close consultation with the California Independent System Operator (CAISO). The Commission should defer development of new RTP tariffs until MRTU implementation is completed and at least 12-18 months of MRTU data is available.

Section VII: Residential rate issues

Time of use (TOU) and critical peak pricing (CPP) rate options are already in the process of being made available to all residential customers. PG&E plans to request authorization soon for a complementary peak day rebate program. These are programs that PG&E believes it can successfully implement for residential customers even while AB1X rate protections remain in place.

Section VIII: Critical peak pricing

PG&E summarizes the status of its CPP rate programs for large and small customers, and describes the successes of its current CPP program for large customers.

Section IX: Relationship to reliability-oriented and other demand response programs

Reliability-oriented demand response tariffs and programs should provide customer load reduction resources that will help to improve electric system reliability at times when conventional supply-side generation resources are not sufficient to meet load. PG&E supports allowing customers to participate in multiple programs provided adequate measures are in place to avoid double payment for the same kilowatts of load reduction.

Section X: Timing of tariff development and roll-out

Many of PG&E's existing dynamic pricing options and tariff programs can be further refined or developed during PG&E's current GRC cycle. However, action on developing RTP tariffs should be deferred to PG&E's 2011 GRC because publicly available day-ahead market prices are not yet available from the MRTU, and because a 12 to 18 month track record of prices from the MRTU should be reviewed before it can be determined how best to use this price information as inputs to the RTP tariffs.

Section XI: Customer education

The primary objective of PG&E's customer education and marketing is to help customers better understand their options, the changes taking place, and the potential for participation in dynamic pricing so that they can make informed choices and implement those options that will yield the best overall result based on their individual circumstances.

Section XII: Enabling technology

PG&E supports helping customers choose appropriate enabling technology for automated demand response participation, and will continue to monitor developments in the emerging market for such technologies.

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Respectfully Submitted,

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ATTACHMENT

PG&E COMMENTS ON DYNAMIC PRICING QUESTIONS

I. Objectives of dynamic pricing and time-differentiated rates

Under this subject heading, PG&E urges the Commission adopt clearly defined and narrowly stated policy goals for its dynamic pricing investigation.

1. What are the objectives of dynamic pricing and time-differentiated rates? How should the various objectives be prioritized? Some objectives, in no particular order of importance, are listed below:

- Reflect marginal cost of electric service. If the price faced by a consumer is close to the marginal cost of providing the electric service, the consumer can make efficient decisions and adjustments in usage patterns. Consumers may be able to lower their overall energy costs by reducing their electricity consumption during higher cost periods or shifting consumption from high cost to low cost periods.

- Flatten the load curve. The electric utility must make capital investments and contractual commitments to satisfy peak electric demand. Some of the generation, distribution, and transmission capacity is only needed during limited hours each year. Such investment may be avoided in the future if customers' rates are higher during peak hours and lower during off-peak hours, providing an incentive for customers to shift usage from peak to off-peak hours through changes in behavior and technology.

- Reduce load in the face of short-term supply shortfall. Unforeseen supply shortfalls can lead to involuntary curtailment of electric service to consumers. The probability of involuntary curtailment may not be reflected in the wholesale price. Tariffs that are specifically designed to reduce load in the face of supply shortfalls could help to avoid involuntary curtailment.

<u>Comments</u>: PG&E believes the first-stated of these three goals (developing rates that reflect marginal cost of providing service) should take precedence over the latter two. It is reasonable to expect that dynamic pricing options which closely reflect marginal costs will also afford new and economically appropriate incentives for flattening the state's electric load curves and so reducing potential exposure to short-term supply shortfalls. "Flattening the load curve" should not be taken as a goal in and of itself, because this does not provide a yardstick for measuring how flat the load curve might best be made, or for distinguishing artificial incentives from those that make economic sense. Similarly, customer response to dynamic pricing options that closely reflect marginal costs should help reduce the frequency and severity of potential short-term supply shortfalls. If and when such shortfalls still occur, however, programmatic responses (e.g., load curtailments under interruptible and curtailable rate programs, direct load control program operations, and similar programs with same-day load response capabilities) are likely to prove much more effective than the limited load reductions that might be available from customer response to same-day or even shorter lead-time price signals.

2. How should dynamic pricing policy be coordinated with other policy and rate design considerations such as energy efficiency, greenhouse gas emission reduction, rate stability, rate simplicity, cost causation, and utility cost recovery?

<u>Comments</u>: PG&E offers the observation that simpler and more narrowly stated policy goals (e.g., "where reasonable, rates should be closely aligned with marginal costs") might serve to reduce the potential for overlap with competing proceedings. The competing policy goals listed above are all important, and will require the Commission's careful attention to balance multiple objectives. By adopting clearly stated and narrowly defined policy goals for this proceeding, the Commission should be able to somewhat reduce the burden of coordinating its actions here with those set forth in other proceedings.

PG&E cautions that the list of other related policy and rate design considerations given above is far from inclusive – for example, neither the currently pending Demand Response OIR (which will produce new standards for measuring load impacts and evaluating cost effectiveness of demand response resources including rates) nor the ongoing energy procurement and resource adequacy rulemakings have been explicitly identified in the list above.

II. Rate options

Under this subject heading, PG&E urges the Commission to develop new dynamic pricing options and demand response programs while preserving customer choice, and also to focus the greatest attention on those rate classes, customer groups and end uses with the greatest potential for producing significant new sources of demand reductions.

1. What rate options should be offered to each type of customer, including bundled, direct access, Community Choice Aggregation (CCA), and net metering? Dynamic rates could include some or all of the following rate strategies:

- Peak, mid peak and off-peak period time-of-use (TOU) rates.
- TOU rates that have more time periods, such as hourly.
- Real time prices (RTP).
- Pre-defined high super peak rates during critical peak periods, or Critical Peak Prices (CPP).
- Rebates during critical peak periods.
- Any other?

Comments: As a general principle, PG&E believes that larger commercial and industrial customers are able and ready to respond to more complex sets of rate options than are smaller commercial and most agricultural customers. When new hourly forward market prices become available through the CAISO's Market Redesign and Technology Upgrade (MRTU) process, it is possible that they will be useful for the purpose of establishing new RTP rate choices for the largest commercial and industrial customers, as discussed under Section VI of these comments. (Rate options for residential customers are discussed separately, under Section VII of these comments.)

TOU and CPP rate options are already available for all industrial and commercial bundled service customers with demands of at least 200 kW, and additional demand response programs are also available to certain smaller customers participating in demand aggregation programs. Additional choices will become available for more customers as the advanced metering infrastructure (AMI meters) authorized by D. 06-05-028 is fully deployed. However, PG&E would caution that demand response expectations should not be set too high for commercial customers with less than 200 kW of demand and for most agricultural loads, because there is substantial evidence that these groups of customers are among those with the lowest demand response potential. Finally, TOU rate options are already available for nearly all residential and small commercial customers, and additional choices will be available to these customers as the AMI meters are deployed.

PG&E believes that dynamic rate options should continue to be focused on the generation component of electric rates. For this reason, the utility rates paid by direct access, CCA and net metering customers would not be affected by policies established in this proceeding, as their generation service is either provided by others (DA and CCA), or is substantially self-provided (in the case of net metering customers).

2. Which tariffs should be voluntary, default with opt-out provisions, or mandatory?

Comments: PG&E supports maintaining customer choice and urges that the Commission carefully review the prior record of extensive and broadly based customer concern with the potential impact and adverse customer reception of rate changes that might be perceived as unwanted new regulatory mandates rather than as attractive new service choices. In this light, PG&E urges the Commission to review the record from the generally unsuccessful "Default CPP" proceeding of 2005 and 2006 (A. 05-01-016), which ended without the adoption of any new rate options – and thus to proceed cautiously before adopting new tariffs except on a voluntary basis.

PG&E also asks that the Commission exercise caution in defining applicability for new tariff options or programs, so as not to unnecessarily bifurcate existing rate classes. To the extent reasonable, new tariffs and programs should be developed which will be applicable for all bundled service customers within given rate classes (rather than unnecessarily creating new subdivisions within existing rate classes).

3. What are the advantages and disadvantages of rebates as an alternative to rates?

Comments: Please see Section VII of these comments (on residential rate issues) for additional discussion of this issue. In brief, PG&E believes that peak period rebate programs for residential customers may offer significant advantages from the perspective of ready customer understanding and compliance with Assembly Bill 1X (AB1X) requirements, which generally prevent customers from being assigned to any new rate schedules or programs that would increase their charges for Tier 1 and Tier 2 usage. Potential disadvantages for rebate programs result from the need for customer-specific "baseline" measures from which to determine those load reductions that would qualify for rebates – where issues could arise as to the fairness and accuracy of such baseline measures.

4. Should automatic load control be considered as a substitute for dynamic pricing rates?

Comments: PG&E believes that automated load control devices (whether supplied by the utility or adopted by individual customers) may prove to be good complements to expanded dynamic pricing options, rather than substitutes – provided that adequate safeguards are in place to prevent double-payment for the "same" demand reductions. PG&E expects automated load control options will improve over time, and so plans to continue monitoring and evaluating the development of this technology.

5. Should customers be offered a large variety of rate options so that customers can find a rate option that works for them, or should customers be offered a small number of options to avoid confusion, simplify marketing and minimize administrative costs?

Comments: As noted above, PG&E believes that larger commercial and industrial customers will be able and ready to respond to more complex sets of rate options and rate choices than will smaller commercial and most agricultural customers. For smaller customers (including residential customers), PG&E recommends exercising caution and developing smaller numbers of less complex rate options so as to avoid confusion, simplify and streamline marketing and customer education efforts, and avoid incurring administrative costs that might outweigh potential demand reduction benefits.

6. How should accuracy and simplicity be balanced in rate design?

Comments: As noted previously, PG&E believes that larger commercial and industrial customers will be able and ready to respond to more complex sets of rate options and rate choices than will smaller commercial and most agricultural customers. In this context, it is reasonable to expect that more complex rate options can be developed for larger customers while tariff options and demand response programs for smaller customers should put greater emphasis on simplicity. However (as is discussed further in Sections III, V and VI of these comments), PG&E also cautions that the "most accurate" potential rate designs need not necessarily also be the most complex.

7. How should the expected ability of a customer group to respond to time-differentiated rates be taken into consideration?

Comments: There is a well-established consensus that the greatest demand response potential lies generally at the two "ends" of the electric customer spectrum as measured by size: among residential customers with significant air conditioning loads, and with the largest industrial and commercial customers with significant re-schedulable process loads. For smaller and mid-sized to moderately large sized commercial facilities, "everyday" energy efficiency opportunities probably offer greater opportunities for load reductions than would dynamic pricing options or new demand response programs targeted at only the highest load days. With these considerations in mind, PG&E urges the Commission to focus the greatest part of its attention on developing new dynamic pricing options and demand response programs for those customers with the greatest potential for producing significant new demand reductions – meaning, for the largest industrial and commercial customers with significant process loads, together with residential customers with significant air conditioning usage.

8. For customers that operate off-line and peaking generation facilities, how should the need to use system power for start-up operations be addressed?

Comments: To the extent that most such customers in PG&E's service area receive standby service under a separate tariff, this question is largely moot from PG&E's perspective. PG&E would recommend excluding the standby service tariffs from new dynamic pricing and demand response efforts or requirements – in part, simply to avoid diverting resources and attention from market segments where there is greater load reduction potential. PG&E also cautions that the Commission should exercise caution so as to avoid creating any potential or unintended new disincentives that might impair the operation of third-party generation resources during critical peak periods.

9. What is the expected response of demand to rate options, taking into account results of pilot programs and relevant studies?

Comments: PG&E believes information of this type to be of somewhat limited usefulness, given the limited information now about what menus of new dynamic pricing tariffs and demand response program offerings might be developed as a result of this proceeding. However, it is possible that additional information will be made available in the final report expected from the Demand Response Research Center (DRRC) and its consultants.

10. Should customers be offered bill protection during an initial time period to learn how a rate might impact their bills?

Comments: Yes. PG&E is supportive of including first-year bill protection as new tariff options are introduced. PG&E believes that first-year bill protection is an extremely effective means of encouraging customers to test new rate options.

11. How would offering bill protection affect customers' response to dynamic pricing tariffs?

Comments: PG&E believes that including first-year bill protection as one component of most new dynamic price offerings will help promote the greatest possible customer adoption and long term participation rates for dynamic pricing. PG&E has learned from market research studies that many customers who are risk averse will be much more concerned about their potential exposure to possible bill increases, rather than motivated by the possibility of achieving bill decreases. Bill protection will remove the downside risk of trying a new rate for customers with these concerns. From this perspective, offering first-year bill protection should greatly enhance overall customer response to dynamic pricing.

12. What are the potential distributional impacts of dynamic pricing rates?

Comments: It is not possible to provide specific bill impact ranges or distributions at this point in time, given the limited current information about what types of new dynamic pricing tariffs and demand response program offerings might be developed in this proceeding. However, the distributional impacts of *any* new dynamic pricing tariffs will principally depend on the product of the following two major factors:

(1) What fraction of the average customer's total annual bill will reasonably be assigned to the new dynamic component of the tariff? (Equivalently – for any given rate class, what fraction of the annual revenue requirement for this rate class would be assigned to the dynamic component of the tariff?)

    For example, when comparing a tariff that puts 10 percent of the average customer's total bill into "dynamic" charges to a tariff with peak charges that are twice as high and so for which the dynamically-assigned charges would account for 20 percent of total revenue (with everything else held equal), the second tariff would have twice as broad a distribution of potential bill impacts.

(2) How widely distributed are the load shapes of individual customers within the class, when measured with respect to the average load shape for the class?

    As a general matter, PG&E would expect to find wider ranges of load shape variation for rate design approaches that assign progressively higher costs to progressively smaller numbers of hours. For example, there will generally be less variation across customers if total usage during summer on-peak TOU hours is measured (as a fraction of total summer season use) compared to the variation in usage shares during a much smaller number of critical peak hours.

PG&E would also caution that: (1) dynamic pricing tariffs will tend to create much greater *monthly* bill volatility for many customers, even if the distributional impacts appear modest if evaluated on an *annual* basis (which is the usual standard for comparison); and (2) additional distributional impacts will result if the dynamic tariff differs substantively in structure from the default tariff (e.g., if volumetric charges were to replace demand charges for large industrial customers, or if simple volumetric rates that varied by season were to replace the inverted-tier charges for residential customers).

III. Components of dynamic pricing tariffs

PG&E cautions that visible forward market prices from the MRTU are not yet available, and it may take some time after MRTU implementation begins to determine the suitability of MRTU prices for ratemaking purposes.

1. Which utility costs vary over time, vary with volume delivered, vary with demand, and/or are fixed? Which utility costs are fixed in the short run, but vary in the long-run?

Comments: The questions posed here are ones at least as much of judgment as of fact. PG&E also cautions against overly casual use of the term "fixed" with regard to specific costs – to a large extent, distinctions between "fixed" and "variable" costs can turn on over what time scale the costs in question would vary. Also, the term fixed cost is sometimes used to indicate costs that vary with the number of customers in a given class or for whom a given service is provided (e.g., metering, billing, customer hook-up, etc.) However, as noted in Section II, PG&E thinks it reasonable to restrict the scope of discussion in this proceeding to the generation component of rates, and so will address only generation-related costs in response to this question.

As a general matter and within the "generation" component of rates, the costs of procuring energy are usually treated as costs that vary with the volume delivered, while the costs of acquiring and maintaining sufficient generation capacity to meet daily and annual peak load requirements are usually treated as costs that vary with demand. However, the nature of the incremental procurement costs that might be avoided or incurred in response to changes in the volumes delivered may be quite different depending on the lead time with which such changes in consumption might be known. Just as one example, changes in consumption that are known a day in advance could result in additional or avoided procurement costs reflecting transactions made at day-ahead forward market prices, while consumption changes that are more unpredictable or occur more nearly in real time may result in incremental or decremental transactions made at hourly or even 10-minute forward market prices. Moreover, entirely different incremental or decremental procurement costs might attach to significant load changes known a month or a year in advance. And similar questions of time scale would arise for demand-related procurement costs. Additional complications are raised for demand-related costs where consideration must be given to how reasonable weights can be assigned to load reductions in different hours at and near the annual peak. Finally, complex allocation questions are raised by demand-related generation costs – clearly, a kilowatt of demand reduction that is known to be available for every hour at and near the annual peak will be more valuable than a kilowatt of demand reduction that is available only for a small number of hours, or even for just one hour. However, demand-related costs are fundamentally denominated in units of dollars per kW and dollars per kW-year, so some form of allocation method is necessary to convert such costs to units of dollars per kW-month (for recovery through generation demand charges) or dollars per kWh (for recovery through CPP charges or in the demand-related component of an RTP rate).

2. What costs should be recovered through the time-variant portion of the rate?

Comments: As noted above, PG&E is restricting its answers under this heading to the recovery of generation-related costs. Based on the considerations described in response to Question 1 of this section, PG&E believes it reasonable to recover all generation-related costs through a combination of time-varying demand and energy charges. Current ratemaking practice generally divides generation cost recovery between demand and energy charges in approximate proportion to their respective shares of total marginal cost. Further, the actual level of the combined generation demand and energy charges will be set so that total generation charges will recover the total generation revenue requirement (including any necessary generation balancing account adjustments), which may result in rates being set at levels that are either higher or lower than the underlying marginal costs.

For the generation component of rates, PG&E believes that demand-related costs should generally be recovered through generation demand charges – which are usually set as monthly charges per kW of maximum demand taken during pre-established peak periods. Under some forms of CPP and RTP, it will be reasonable to replace some or all of the generation demand charge with dollar-per-kWh charges assigned to smaller numbers of hours with loads at and near the system peak. However, when such tariffs are offered as alternatives to or substitutes for conventional TOU demand-and-energy tariffs, some consideration must be given to bill impacts that would result from such structural tariff change alone, independent of changes that result when customers respond to the prices under the new tariff. To the extent that demand-related generation costs can be recovered entirely through demand charges (or capacity charges that are applied to a limited number of hours), this will allow for the time-varying generation component of the rate to be set at levels that recover only short-term energy procurement costs during the great majority of operating hours each year.

3. How should time variant costs be determined?

<u>Comments</u>: There are a variety of sources for establishing both the demand-related and energy-related portions of total time-varying generation costs. For example, demand-related costs can be derived from the annualized capital cost of a combustion turbine or from the cost of other peaking resources, and then may be assigned to individual hours (or blocks of hours) by any number of means. Energy-related marginal costs are currently set by scaling an assumed annual average dollar-per-MWH marginal cost to historic price curve information, although it is hoped that MRTU price information from the CAISO will be useful for this purpose at some point in the relatively near future.

From a ratemaking perspective, and noting that generation rates will be set to collect the total generation revenue requirement rather than total marginal cost, PG&E notes that three of the most important cost factors for the purposes of setting either TOU-based generation rates or more dynamic generation prices will be:

(1) the relative shares of total generation marginal costs attributed to demand-related and energy-related marginal costs, respectively;

(2) the relative weights assigned to load in hours at and near the system peak (as used for the purpose of allocating the demand-related share of total costs and setting the demand-related portion of total generation rates for individual hours or groups of hours); and

(3) the assumed price curve relating energy-related marginal costs as a function of daily and hourly load levels (as used for the purpose of setting the energy-related portion of total generation rates).

From a practical perspective, differing methodologies or assumptions for determining marginal generation demand and energy costs will frequently affect only how generation rates are divided between demand and energy-related charges, without having any effect on overall rate levels.

4. What is the appropriate time granularity for measuring electric service costs in connection with dynamic rate design – annual, monthly, weekly, daily, hourly, ten minutes, etc.?

Comments: As a practical matter, PG&E believes that any time granularity finer than hourly forward market prices on a day-ahead basis will be of limited usefulness for ratemaking purposes. PG&E's own customers have always expressed strong preferences for greater advance notice rather than less in order to adjust their operations in response to dynamic pricing signals, and it has proven difficult to find credible evidence of customers responding to same-day prices (let alone hour-ahead or 10-minute-ahead prices) in other jurisdictions.

Moreover, as noted in response to previous questions: (1) only a small share of total procurements are likely to be incurred in same-day and shorter lead time transactions; and (2) generation rates must be set to recover the total revenue requirement and so cannot reasonably be tied directly to specific marginal cost measures in isolation from other considerations. These two factors are additional reasons for concluding that same-day market prices will be of limited practical use for dynamic rate design, regardless of whether such price information is made available from the MRTU or is derived from some other source.

5. How closely should the time profile of dynamic rates be aligned with the time profile of service costs?

Comments: In general, and based on the considerations described in Section II of these comments, PG&E believes that rates for the largest customers are those that might reasonably be set to vary on the shortest time intervals. Even for these customers, however, PG&E believes that setting hourly prices on a day-ahead basis is a natural limit on reasonable time profiles for dynamic tariffs. PG&E also cautions that, as discussed in response to previous questions in this discussion, there is no single time profile of service costs which can reasonably serve as a basis for dynamic tariffs. The state's utilities acquire power for their bundled service customers from a variety of sources and with a number of different relevant time profiles. PG&E encourages comments from other parties, input from the DRRC and its consultants, and active discussion at the November workshops as to how best to merge cost information taken from this great variety of currently relevant time scales into one or more cost profiles that might be most useful for establishing dynamic tariffs.

6. If a time variant rate requires market price information, will the rate require information from the California Independent System Operator's (CAISO) Market Redesign and Technology Update (MRTU)?

Comments: Yes. PG&E presumes that market price information from the MRTU will at some time in the future be quite useful for the purpose of establishing dynamic tariffs. PG&E cautions, however, that MRTU price information will probably never be useful as a "sole source" of price inputs for the dynamic tariffs. As discussed above, PG&E believes there are important unresolved questions as to how best to merge price information across a variety of time scales and how to address differences between marginal cost revenues and the total generation revenue requirement as more granular and more frequently varying dynamic prices are introduced. PG&E also believes that a minimum of 12 to 18 months of MRTU price information will be needed before its usefulness for future ratemaking purposes can be determined. For example, it will be important to know how much of the state's power is being contracted for across which of the MRTU sub-markets (e.g., day-ahead, hour-ahead, real-time) and whether or not these shares are relatively stable over time. It will also be important to observe how the time profiles of MRTU prices for each market vary over time, whether trading is thin or robust in each market, and whether reasonable relationships can be found between prices and loads.

7. Should some costs be recovered through a flat customer charge, demand charge, and/or non-varying per kW-hour charge?

Comments: Yes. PG&E believes that most customer service, customer hook-up, and metering and billing costs should continue to be recovered through a combination of flat customer charges, non-TOU demand charges, and non-time-varying volumetric charges. The same is true for most T&D-related costs (with the exception of limited portions of the distribution revenue requirement which are recovered through time-varying rates for some customer classes), and also for most non-bypassable charges such as Competition Transition Charges (CTCs), and nuclear decommissioning, public purpose program, and ERB and DWR bond charges. As also noted elsewhere in these comments, PG&E believes the primary focus of this proceeding should be on the development of dynamic pricing tariffs for recovery of generation-related costs from bundled service customers.

8. Should the components of the rate that are collecting fixed costs vary over time? If so, how should fixed costs be allocated to different time periods?

Comments: As noted above, PG&E finds it reasonable that all generation-related costs be recovered through time-varying charges. As PG&E believes the primary focus of this proceeding should be on the development of dynamic pricing tariffs for recovery of generation-related costs from bundled service customers, this question about rate components that provide for "fixed cost" recovery is moot from PG&E's perspective.

9. How should the costs for public purpose programs and other non-bypassable charges be reflected in the time-variant portion of rates, if at all?

Comments: As noted above, PG&E believes the primary focus of this proceeding should be on the development of dynamic pricing tariffs for recovery of generation-related costs from bundled service customers. PG&E believes that rate setting for public purpose program costs and other non-bypassable charges should be regarded as outside the scope of this dynamic pricing investigation.

10. What balance between fixed and time-variant costs will achieve the objectives of the tariffs?

Comments: PG&E believes the primary focus of this proceeding should be on the development of dynamic pricing tariffs for recovery of generation-related costs from bundled service customers and that all generation-related costs can be treated as time-varying and so recovered through time-varying charges. From this perspective, there is no need for further consideration here of balancing fixed costs versus time-varying costs.

11. Should direct access and CCA customers be able to participate in time variant rates?

Comments: PG&E believes the primary focus of this proceeding should be on the development of dynamic pricing tariffs for recovery of generation-related costs from bundled service customers. From this perspective, ratemaking for direct access and CCA customers would be entirely outside the scope of this proceeding.

12. If a rate is intended to reduce load in the face of a short-term supply shortfall, should the design of the rate differ depending on whether the shortfall is forecast on a day-ahead or day-of basis?

Comments: As noted in Section I of these comments, PG&E believes that programmatic responses (e.g., load curtailments under interruptible and curtailable rate programs, and direct load control program operations) will continue to be the most effective means of reducing load in the face of critical short-term supply shortfalls on a same-day basis. As noted above, PG&E's customers have always expressed strong preferences for greater advance notice rather than less in order to adjust their operations in response to dynamic pricing signals, and it is difficult to find credible evidence from other jurisdictions for real customer load response to same-day prices, let alone hour-ahead or 10-minute-ahead prices.

IV. Recovering the revenue requirement

PG&E observes that costs and revenues should be reasonably well correlated if well-designed and cost-based dynamic tariffs are adopted. This would mean that the revenue under-collections that might result from lower than expected sales should be partially offset by lower procurement costs relative to the original forecast used to set rates (and conversely, if electricity usage is higher than expected).

1. How can rates be designed to both recover the revenue requirement and communicate price information?

Comments: In brief, rates are designed to recover a revenue requirement by developing a sales forecast in sufficient detail so as to include full billing determinants and then setting rates such that the revenue requirement is recovered when the test year billing determinants are multiplied by the rates. This statement is, of course, something of an over-simplification – among the challenges in developing dynamic tariffs is that whatever the complexity of the proposed tariff, this must be matched by ever-increasing detail in the sales forecast and associated billing determinants. Moreover, to the extent that either the rates themselves are *not* set in advance (as with an RTP rate) or the duration of some of the rate periods are allowed to float (as with certain types of CPP rates), either the rates, the billing determinants, or both will be subject to much greater forecast uncertainty than is usual for ratemaking purposes.

PG&E's adopted CPP tariffs strike a reasonable balance between recovering the revenue requirement and communicating price information – that information being that "*significant costs are incurred to make peaking capacity available for a limited number of peak load hours each summer*." These are currently designed as revenue neutral "overlay" tariffs (customers pay all ordinary charges under their standard tariff, then pay additional charges during CPP periods while receiving offsetting discounts that apply to usage outside of CPP periods), where fixed CPP overlay prices are designed to be in effect on a fixed number of peak load period hours each summer. The extra charges that are applicable during CPP periods add between $30 and $50 per average kilowatt of CPP period load (depending on rate class), and these extra charges are offset by the credits customers receive for usage outside of CPP periods (the offset is "exact" for customers with class-average load shapes, as defined by the balance between their own CPP period and credit-period usage). Moreover, to the extent that the $30-$50 per kW price signal is in reasonable accord with those short-term procurement or longer-term capacity acquisition costs that might be avoided by regular load reductions during 50-75 CPP hours each summer, there will be a reasonable balance between CPP-related revenue reductions (relative to a forecast) and potential reduced procurement costs.

As noted above and discussed in more detail below, this balance will be considerably more difficult to strike if prices or rate design parameters are allowed to "float" more freely, either every hour under an unconstrained RTP tariff, or if the annual number of CPP calls is not fixed at a pre-specified level (under some more "variable" forms of CPP tariffs).

2. How can rates be designed to avoid large periodic rate adjustments to recover revenues?

Comments: To the extent that new dynamic tariff options are established on a revenue-neutral basis, and that cost savings available under these tariffs are in reasonable accord with truly avoidable procurement costs (for capacity and energy), this should reduce the risk of requiring large future-year rate adjustments for balancing account over- or under-collections. Conversely, there will be a greater risk of large future-year rate adjustments if dynamic price signals are artificially inflated (e.g., with the intent of incenting additional demand response – beyond that which might be undertaken in response to price signals more closely aligned with actual costs), or if rate design approaches are used that put large shares of the revenue requirement at risk of under- or over-collection due to forecast or weather-related uncertainty (e.g., CPP rates with no annual minimum or maximum numbers of program operations, or RTP rates that do not include mechanisms to insure revenue-neutrality in the face of forecast uncertainty.

PG&E cautions that any change in pricing methodology will tend to require subsequent follow-up adjustments to rates to recover revenues, simply because some level of initial revenue shifting must be expected as customers make choices between rate schedules. The pricing methods that are adopted will need to protect base fixed cost recovery from changes in variable costs and revenues. Shifts in the variable costs and revenues can be matched. However, changes in the base fixed cost recovery could also be large enough to influence the overall price signals.

3. Does the utility need to be able to forecast accurately the response of customers to these differential rates?

Comments: To the extent that pricing under the dynamic tariffs truly follows costs, accurate forecasts of customer response may not be of great necessity for the purpose of sales and revenue forecasting and setting annual rate updates. Under the assumption that unexpected demand reductions materialize under these tariffs (beyond those that might be assumed in the initial sales forecast), these demand reductions should yield concomitant procurement cost savings. However, it is also possible that improved forecasting accuracy for customer response to certain kinds of dynamic pricing tariffs would make it possible to realize additional short-term avoided cost savings (e.g., if such forecasts allow the utility to forego specific contractual commitments). PG&E is hopeful that such short-term forecasting accuracy improvements will be realized as additional experience with new dynamic tariff options is developed.

4. Do the utilities need reliable estimates of price elasticities of demand for customers to make sales projections?

Comments: PG&E will use the best available econometric information to prepare future sales forecasts. As discussed further under Question 1 of this section, a complete forecast for ratemaking purposes requires forecasts of total sales (usually at the class level) together with additional information in sufficient detail to develop full billing determinants at the level of detail needed to match the applicable rate structures for each class. Econometric models are usually used to develop the basic class-level forecasts of total sales, but historic load shape information is generally relied upon for the purpose of developing detailed billing determinant projections.

5. What estimates of price elasticities exist and can be relied upon for rate design purposes?

Comments: PG&E is not aware of any currently available price elasticity estimates that might be germane to the sub-task of extending class-level sales forecasts to the billing determinant level of detail for dynamic tariffs. The econometric models used to develop class-level sales forecasts generally relate total sales to class-average electricity prices, and so neither require nor can make use of additional information at the rate design level (e.g., inverted tier pricing structures, demand versus volumetric charges, TOU price ratios, etc.). At the rate design level of detail, no single price elasticity index could even be defined for each rate class; what might be needed would be a complex set of econometric models relating demand by TOU period and type of charge (for example) to prices and demands across all TOU periods and types of charges. Instead, historic load shape information is used to develop billing determinants after the overall sales forecast has been prepared. PG&E anticipates maintaining this approach for the foreseeable future – while noting that customer load response to dynamic tariff options should produce further load shape changes which would be reflected in subsequent sales forecasts and billing determinant projections.

6. If customer responses to dynamic pricing tariffs result in revenue over or under-collections, should the over- or under collection be addressed by adjusting rates within the customer's class, or should the over- or under collection be addressed by adjusting rates for all customer classes?

Comments: PG&E believes that revenue over- or under-collections associated solely with customer response to the dynamic tariff options should continue to accrue to the Energy Cost Revenue Recovery Account (ERRA) for future recovery through adjustments to bundled service rates for all customer classes. As noted above, such over- or under-collections should at least to some extent track concomitant increased or reduced procurement costs – which would ordinarily accrue to the cost side of the ERRA. Any newly developed system of tracking dynamic tariff revenue imbalances would in all fairness also require accounting for the cost side of the ledger. This would introduce additional layers of complexity, layers which PG&E believes to be unnecessary as long as those cost savings realizable under the dynamic tariffs are in reasonable accord with the corresponding avoided costs.

7. If customers' self-selection into voluntary dynamic pricing tariffs results in over- or under-collections, how should the over- or under-collection be recovered – by adjusting rates of customers taking service under the voluntary tariff, by adjusting the rates of all customers within the customers' class, or by adjusting rates for all customers?

Comments: PG&E recommends that revenue-neutral tariff choices be established for each customer class, where these tariffs are revenue-neutral for a customer with the hypothetical average load shape within each class (subject to possible inclusion of hedge premiums and participation credits, as discussed in response to Questions 9 and 10 of this section, and also under Section V of these comments). Where individual customers with better-than-average load profiles might realize self-selection savings under a dynamic tariff option, PG&E would observe that such customers can be seen as having selected a cost-based rate which more accurately reflects their own cost of service. Thus, PG&E would not recommend reconciling self-selection revenue losses at any more granular level of detail than the class level. Moreover, if comparable ranges of choices are developed for all rate classes, it is likely that PG&E would recommend reconciling self-selection revenue losses only through the ERRA and so across all bundled service customer classes. PG&E notes that class-level reconciliation of self-selection revenue losses could prove intractable, given that the self-selecting customers will most likely undertake additional demand reductions or load shifts after enrolling under their choice of dynamic tariffs – thus requiring some means of distinguishing self-selection bill savings from those bill savings realized in response to bona fide demand reductions or load shifts.

8. What mechanisms should the utility use to recover over- and under-collections from customers?

Comments: As also discussed in response to the two preceding questions in this section, PG&E recommends that any revenue over- or under-collections from the dynamic tariffs continue to accrue through the ERRA, for later reconciliation through future adjustments to the generation rates paid by all bundled service customers. As also noted above, these adjustments should tend to be offset over time by corresponding incremental or decremental procurement costs, which are also reconciled through the annual ERRA adjustments.

9. Should dynamic pricing tariffs be revenue-neutral with respect to flat and less time differentiated tariffs, or should the revenues collected by dynamic pricing tariffs differ from the revenues collected by flat and less time differentiated tariffs due to the incorporation of hedging premiums or participation credits?

Comments: PG&E recommends that the basic rate design approach used should be to establish revenue-neutral tariff choices for each customer class. PG&E will look to further information from the DRRC and its consultants and discussion at the November workshops before taking a formal position on whether hedge premiums should be applied to the less time-differentiated tariffs as a matter of policy. PG&E will note here that its approved CPP tariffs for residential and smaller commercial customers (as authorized by D. 06-05-028) include provisions for additional participation credits to be included in these rates, beyond those credits needed to establish these rates on a revenue neutral basis. As originally proposed by PG&E, the revenue losses associated with these participation credits will be reconciled at the class level by applying offsetting adjustments to the rates paid by non-participants. This approach is similar in its practical function to what would be accomplished by applying "hedge premiums" to the less time-differentiated schedules and using revenue from the hedge premiums to offer somewhat lower rates under the dynamic pricing tariffs. However, PG&E's proposed approach was simply predicated on incenting additional participation under the new CPP tariffs while maintaining class-level revenue neutrality and not imposing unreasonable additional costs on non-participants – adopting this approach did not require establishing a theoretical or policy basis for the hedge premium concept, which PG&E is not yet convinced has a sound foundation.

10. If the incorporation of hedging premiums or participation credits results a revenue over- or under-collection, how should the revenue over- or under- collection be treated?

Comments: If a system of hedge premiums and participation credits is established, PG&E would recommend that revenue be reconciled within each class for this component of the dynamic tariffs on a forecast basis. The approach that has already been adopted for PG&E's CPP tariffs for residential and smaller commercial customers provides a reasonable model for how this can be accomplished, with adjustments to the less time-differentiated default tariffs which will be applied in such a way as to enforce approximate class-level revenue reconciliation.

11. If the average cost to serve customers on a particular dynamic pricing tariff is less than the cost to serve customers not on the tariff, can the tariff be structured so that the dynamic pricing customers have a lower average cost?

Comments: This purpose would be accomplished as a simple matter of course for customers electing service under cost-based dynamic pricing tariffs, irrespective of whether hedge premiums and participation credits are included in the rate design. To see why this is true, consider a simple tariff with volumetric rates set at 20 cents per kWh during the summer months and 12 cents per kWh during the winter. A customer taking service under this tariff whose usage is divided equally between the summer and winter (and so has a flat year-round load profile from the perspective of total monthly electricity use) will then pay an average annual rate of 16 cents per kWh. In contrast to this, consider a "peakier" customer who uses three summer-season kWh for each kWh of winter-season usage. Under the same tariff, this customer would pay an annual average bill of 18 cents per kWh.

12. If the utility incurs incremental costs to implement dynamic pricing tariffs (e.g., administrative costs, equipment, education), how should the incremental costs be recovered?

Comments: PG&E believes that reasonable program implementation costs should be recoverable in rates from all customers, using the same methods for budget review and cost recovery as is already being used for 2006-2008 Demand Response Program costs.

V. Hedging

PG&E notes that a system of voluntary participation credits (paid for by small premiums in the rates paid by non-participants) can serve the same practical purpose as that of applying explicit hedge premiums to non-participants' rates. PG&E also cautions that the concept of hedge premiums may be used quite differently in different contexts, and is not yet convinced that a solid foundation has been established for applying this concept to develop dynamic pricing options.

1. Should customers have the opportunity to hedge the price risk under some or all of the dynamic tariff options?

Comments: PG&E will look to the DRRC and the final report from its consultants together with additional discussion at the November workshops before taking a position on this question. From the information available now, it is unclear what purpose would be served by establishing new dynamic pricing tariffs on a default basis and then establishing additional new mechanisms to limit customers' exposure to these prices. If financial hedging instruments are simply a more complicated means of allowing customers to opt out from default dynamic pricing tariffs, PG&E believes the better approach is to establish a range of tariff options appropriate to customers within each class and permit customers to choose their own preferred pricing plan.

2. Should hedging options be offered by the utility, or should rates be structured so that hedging can be obtained externally in the marketplace?

Comments: As noted in our response to the first question of this section, PG&E is not yet certain that hedging options will be the best way to present dynamic pricing options to most customers. However, PG&E urges caution before any adoption of an approach that involves third-party hedging instruments. One instructive past example of third-party financial instruments gone wrong is the "interruptible rate insurance" debacle from the summer of 2000, when a financial services company enticed some number of SCE interruptible rate customers to purchase "non-compliance insurance," in theory allowing such customers to ignore curtailment orders just when their load reductions might have been most needed.

3. If a hedging premium is incorporated into relatively flatter rates, what should the premium be and how should it be determined?

Comments: PG&E may not object to including hedge premiums and participation credits under some dynamic tariff options, but is not yet convinced that a sound analytical basis has been established for setting such premiums. Please refer to Section IV for additional discussion.

4. Should customers have the opportunity to hedge through a two-part tariff in which part of their consumption is purchased at a fixed rate and the rest is purchased at the dynamic rate?

Comments: PG&E generally opposes such an approach for most customer classes, out of concern that two-part tariffs would be difficult to administer and communicate to the largest body of commercial customers. PG&E is unaware of practical examples of two-part tariffs offered in other jurisdictions to more than just a few of a utility's largest customers.

VI. Sources of triggers and prices for dynamic prices

Under this heading, PG&E recommends that most dynamic price triggers and demand response program operations should be activated and communicated to customers by the utility, acting in close consultation with the CAISO. Development of new RTP tariffs should be deferred until MRTU implementation is completed and at least 12 - 18 months of MRTU data is available.

1. For trigger-based rates such as CPP, who should determine when an event is triggered – the CAISO or the utility?

<u>Comments</u>: PG&E believes that most price-based programs should continue to be administered and operated by the utilities, with operating criteria subject to review by and discussion with the CAISO.

Demand response programs are an integral part of PG&E's supply/demand portfolio and having utilities trigger the event will facilitate the implementation of the Commission's least cost dispatch mandate. CAISO obligations are to maintain the reliability of its entire control area, and it may be using triggers that are control area wide such as total load or average heat rates.

PG&E believes that the utility should have the ability to trigger an event using pre-determined and pre-approved criteria. To the extent there are several criteria to chose from (e.g., forecast demand, forecast temperature, emergency situations, higher market prices), the utility should have discretion to use any of these criteria to trigger an event, as well as to not trigger the event if the situation warrants. For example, it is possible that total CAISO area load may justify an event, but PG&E's load may be moderate or PG&E may have less costly resources on the margin. In such a scenario, PG&E might not trigger the CPP event, while the CAISO would be more likely to.

For those programs that limit the number of calls over a period, the utility should have the ultimate call. Should the example in the previous paragraph be a program with a finite number of hours or events that are allowed and the expectation is that PG&E will call the program at a later time based on a reliable forecast of expected conditions, PG&E may not want to trigger the program at that instant.

2. Should RTP be linked to wholesale market prices or some other price or cost information?

<u>Comments</u>: PG&E believes that the availability of publicly visible wholesale market information will be a prerequisite for the development of new RTP tariffs. However, before such information is used as a basis for setting retail market prices, PG&E assumes that all parties will want assurance that the information is drawn from stable and robustly traded markets.

PG&E believes that RTP tariffs might be linked to published indexes of wholesale prices such as those available from the Intercontinental Exchange. Another source of market pricing information could be ex-post prices published by the CAISO. In either case, however, the end user should be fully aware of how these prices are determined and what they represent. For instance, programs that are price triggered and called on a day-ahead basis should use the day-ahead index as opposed to the CAISO's ex-post prices.

3. If a RTP rate is linked to wholesale market prices, what wholesale market prices should the tariff be linked to?

Comments: Presumably, new market price information from the CAISO MRTU process will be of some use for this purpose. However, for reasons discussed in more detail under Section III of these comments, PG&E cautions that the MRTU is unlikely to produce market prices that can be used for immediate implementation of RTP tariffs. It is also important to recognize that RTP prices might be "linked" to MRTU prices, but the MRTU prices are quite unlikely to be directly usable in and of themselves – in part, because RTP tariffs will need to be designed to collect the same generation revenue requirement as do the less time-differentiated tariffs, so methods will need to be established for reconciling MRTU price information with each utility's overall procurement costs.

Sending hourly-price signals on a day-ahead basis will give customers the opportunity to maximize the level of response because they will have more lead time to adjust their use. For an RTP tariff that is targeting a broad base of customers, linking RTP to day-ahead hourly prices if there is a day-ahead market, or to a day-ahead index if there is no reliable day-ahead market, would be preferable to an approach based on real-time hourly prices.

4. What impact will MRTU and potential capacity market implementation have on the prices used to design RTP and other dynamic tariffs?

Comments: PG&E is hopeful that the MRTU and possible capacity market implementation will be useful for the future development of dynamic pricing tariffs. Unfortunately, however, no information from either of these sources is likely to be available for consideration in this proceeding. As discussed in more detail under Section III of these comments, PG&E is also concerned that a minimum of 12-18 months of MRTU market price information will need to be available before it can reasonably be evaluated for ratemaking applications.

MRTU implementation will enhance the transparency and possible effectiveness of RTP programs. MRTU is expected to provide day ahead hourly granularity, as well as expanded locational pricing below the current zonal limits. MRTU should expand the available locational prices in the real-time market as well, although questions of how to reflect locational prices in broadly available retail tariffs would remain to be addressed.

Since demand response programs participate in Resource Adequacy, it is likely these programs will be eligible to participate in future capacity markets. However, since RTP would be intended to elicit customer response based on their willingness to pay for energy, it is uncertain at this time how and under what conditions it would be possible to recognize their response as firm capacity. There are examples where RTP participants can also participate in the capacity markets, however. For example, in Niagara Mohawk RTP tariff SC-3A, the hourly energy commodity prices are indexed to the NYISO day ahead market's Locational-based Marginal Prices corresponding to the customer's geographic location day-ahead prices, and these prices include ancillary services and other energy delivery costs. These customers are also allowed to participate in the NYISO Installed Capacity Special Case Resources (ICAP/SRC) program. The ICAP/SRC program allows customers that meet certification requirements to offer unforced capacity (UCAP) to Load Serving Entities and to the six-month strip and the monthly reconfiguration auctions that are administered by the NYISO. PG&E will continue to monitor the development of programs of this type and evaluate their potential for application to the evolving procurement markets in California.

5. Will the variation in wholesale market prices impact customer behavior?

Comments: PG&E advises caution in setting expectations too high for customer response to RTP tariffs linked to wholesale market prices, because it is quite likely that the state's planning reserve requirements and renewable resource portfolio standards will produce relatively flat wholesale market prices for the foreseeable future. In the face of relatively flat wholesale market prices, PG&E would not expect a high degree of customer response to RTP tariffs.

If the customer has access to pricing information, however, behavior should be affected. Also, PG&E expects that its upcoming Smart Meter Upgrade project application will enable greater customer access to information such as their own energy usage and applicable dynamic pricing offers, which should lead to higher levels of demand response and energy efficiency.

6. Should tariffs be tied to the day-ahead or the same-day real time price?

Comments: As discussed under Section III of these comments, PG&E believes that the practical limit for RTP tariffs will be hourly prices issued on a day-ahead basis. Thus, day-ahead MRTU prices would likely have the most relevance for RTP tariff design.

Day-ahead notice tied to day ahead prices will give customers more lead time to readjust their operations and should therefore generate more demand response. Thus, any tariff targeting a broad base of customers should be tied to day ahead prices. While more specialized tariffs targeting automatic demand response capability might in the future support using same-day real time prices, PG&E believes that the customer population with the ability to respond at this level will probably always be quite limited.

7. How should the real time price be communicated to customers?

Comments: Using current technology, daily e-mail notification and Internet publication would probably afford the most effective means of customer notification. In the day-ahead RTP case, day-ahead hourly prices could be published at a web-site to be accessed by the customer through the Internet. In a more specialized same-day RTP, price signals might need to be sent directly to automated load control systems at participating customer sites. However, PG&E is not aware of existing load control technologies with this level of capability.

8. Should the RTP rate be a two-part rate with both a fixed price portion for part of a customer's usage and a dynamic portion for the remaining usage?

Comments: As PG&E understands it, references to "two-part" RTP tariffs usually mean that a customer pays a monthly charge tied to the product of the customer's ordinarily applicable standard tariff rates and a fixed reference period load profile for the customer (the "first part" of their bill), together with charges or credits that are applied to incremental or decremental usage above or below their reference period profile (the "second part" of the customer's bill). This is a method that has been used in many jurisdictions to provide for revenue reconciliation with respect to the standard tariff.

This form of RTP tariff can be described as revenue-neutral, given that a customer whose usage exactly matches their reference period load profile will pay the same bill as they would have paid under the standard tariff – under this assumption, there are no charges or credits to be applied when the second part of the bill is calculated. However, if the reference period load profile is set too low (or if a customer chooses service under a contract of this type just prior to a significant expansion of their electricity usage), this form of RTP tariff can be criticized as no more than an incremental sales contract masquerading as a dynamic pricing rate.

PG&E is aware of at least two types of RTP rates that are called "two-part rates." Under the NIMO SC-3A tariff, the commodity portion is unbundled and charged to the customer at the RTP rate, while distribution, delivery and CTC rate components are charged based on the peak demand of the customer. In other tariffs, the customer is charged under the existing TOU tariff prices for their Customer Baseline load (typically established using historical load profiles) and deviations from these baselines are charged at the RTP rate. In the first type, the customer is exposed to the day ahead prices for all of their usage, whereas in the second type they can be regarded as "hedged" for nearly all of their use. Implementation of this second type can be much more difficult, because of difficulties in establishing and administering the customer baseline load profiles.

9. Under a two-part RTP rate, how should a customer's reference level for the fixed portion be determined?

Comments: Under the first type of "two-part" RTP tariff described above, the customer's peak demand each month determines the fixed part of their bill. Under the second type, the customer baseline load profile is priced at the TOU rate and this determines the fixed portion of their bill each month. Under this alternative, there a number of approaches for establishing the reference load profile for each customer, ranging from full 8760 hour load profiles for an entire record period year to approaches that involve more load averaging (e.g., with weekday and weekend load profiles that might vary by month or by season). When customer baselines are used for a two-part RTP tariff, issues may also need to be considered as to whether and how the baseline load profiles should be updated over time.

10. Under a two-part RTP rate, what costs should be recovered in the fixed portion of the rate?

Comments: Under the first type of "two-part" RTP tariff described above, distribution and CTC are recovered in the fixed part of the bill. Under the second type, distribution, CTC and most commodity costs are recovered in the fixed part of the bill.

VII. Residential rate issues

PG&E observes that TOU options are available now, and CPP rate options are in the process of being made available to nearly all residential customers. PG&E plans to request authorization soon for a complementary Peak Day rebate program. These are examples of the types of dynamic pricing and demand response programs which PG&E believes can be successfully implemented for residential customers even while AB1X rate protections remain in place.

1. What dynamic rates should be offered to residential customers while the rate protection offered under AB1X remains in effect?

Comment: PG&E's residential customers can already choose TOU rates, and CPP rates that meet AB1X requirements have been authorized and will become available for residential customers beginning next summer as the new AMI meters are deployed. PG&E also plans to seek authorization for a peak-time rebate program in its upcoming Upgrade application for the AMI project, similar to rebate programs currently under consideration for both SDG&E and SCE. Taken together, PG&E believes these will provide its residential customers with a good range of dynamic rate choices to be available during the period that AB1X remains in effect.

2. What types of dynamic rates can be offered to residential customers if the AB1X rate protection is lifted by the Legislature or is no longer effective?

Comment: PG&E would approach further rate changes for residential customers cautiously, even if AB1X was no longer effective. As also discussed in Section II of these comments, major structural changes can be fraught with unintended consequences and so should be approached with caution. In general, there would certainly be the opportunity to make rate design changes that would allow the generation component of PG&E's residential tariffs to more closely track changes in procurement costs. However, it will also be important to manage unexpected bill impact consequences when rate design changes are made, meaning that changes to the existing inverted-tier structure of the basic residential tariffs should be approached cautiously.

3. How can rates be designed to maximize residential participation while the AB1X rate protection remains in effect?

Comment: As noted above, PG&E believes that the already-authorized complement of TOU and CPP rate options for its residential customers, together with the peak-time rebate program for which it expects to seek authorization soon and combined with emerging smart thermostat and air conditioning control programs and technologies, will provide customers with a good range of choices for dynamic rate options and demand response opportunities during the period that AB1X remains in effect.

4. To what extent do existing residential rates and programs such as increasing block rates and air conditioning cycling fulfill the Commission's policy goals?

Comment: Increasing block rates for residential customers should certainly promote "every day" energy conservation efforts (at least among those high-usage customers who are subject to upper-tier prices); while the current inverted tier rates do somewhat complicate the development of more dynamic rate options, they do not preclude such options – as demonstrated by the range of choices currently being made available to and under development for PG&E's residential customers. Air conditioning cycling programs can be a valuable tool for promoting peak day demand reductions, both on a stand-alone basis and in conjunction with TOU or CPP rate offerings.

5. Could additional demand response be provided if AB1X rate protection were no longer effective? If so, how much additional demand response? What would the potential bill impact be for residential customers if they were able to participate in dynamic pricing rates?

Comment: PG&E expects to develop significant new demand response capabilities in the residential market over time, especially as AMI technology is more fully deployed. As noted above, PG&E believes this can be achieved even during the period that AB1X rate protections remain in effect. As discussed above and at such time as AB1X is no longer in effect, there will be further opportunities to develop residential tariffs that might more closely track changes in procurement costs, and this would be expected to elicit additional demand response. Please see Section II of these comments for discussion of bill impact projections and the most important factors that would affect these projections (e.g., what fractions of the average customer's bills are assigned to new dynamic rate components, and in what ways the revenue-neutral point for a new rate structure might deviate from current rates).

6. How would existing residential rates and programs such as increasing block rates and air conditioning cycling be affected by dynamic pricing rates for residential customers?

Comment: As discussed elsewhere in these comments, PG&E has approached development of dynamic pricing offerings and demand reduction programs for residential customers in such a way as to complement rather than preempt the current tier structure and to integrate air conditioning cycling opportunities with other rate and program offerings.

7. Should low-income residential customers be offered discounted dynamic rates or other dynamic rate options?

Comment: PG&E's qualifying low-income customers are already offered TOU rate choices now and will be offered CPP rate choices beginning in the summer of 2008, on nearly the same basis as such choices are offered to all other customers – in essence, qualifying lower income customers receive those rate discounts for which they are eligible as part of the standard portion of their bill and then see the same dynamic price signals as all other customers for the portion of their bill that is determined by the time-differentiated price signals. PG&E believes this will continue to be an effective means of offering dynamic rate options for all of its residential customers.

VIII. Critical Peak Pricing

PG&E's current CPP rate program for large customers has proved quite successful, and PG&E is hopeful of achieving similar success with its new CPP rates for smaller customers.

1. What should a CPP rate be based on? Is there a reliability value that is not included in wholesale power prices that should be incorporated into the tariff?

Comment: PG&E believes that effective CPP rate offerings can continue to be based in largest part on generation capacity avoided costs, with some discounting to reflect constraints on CPP program operations (such as monthly and annual operating limits, and the requirement that CPP operations normally be initiated on a day-ahead basis).

2. How long should the critical peak period be?

Comment: PG&E's current CPP programs are structured around a four-to-five hour peak period on summer weekdays, with provisions for 12 to 15 program operations each summer. PG&E believes this structure is reasonable and can be maintained for the foreseeable future.

3. When should a utility be able to trigger a critical peak period – during summer peak hours only, during summer mid-peak and off-peak hours, during winter hours?

Comment: PG&E believes that its current CPP offerings strike a reasonable balance between giving customers a reasonable understanding of when CPP prices will be activated while also providing adequate coverage of those periods when peak loads are expected to be at their highest levels and generation shortfalls are most likely to occur.

4. How can a CPP tariff be structured to allow for a variable number of events each year while still recovering the revenue requirement?

Comment: As also discussed in Section IV of these comments, it is simply not possible to structure a CPP tariff that recovers the revenue requirement on an annual basis and also allows for a variable number of events each year.

5. Is the potential customer savings or cost great enough under a CPP rate to motivate a customer response?

Comment: PG&E has successfully marketed its current CPP program for larger customers for approximately the last five years, and a significant fraction of the large customer population (now approaching 10 percent as measured by sales volume) currently takes service under this rate. For the large customer market, while CPP is still a relatively small component of the overall demand response portfolio (as measured by dependable load reduction capability) a significant number of customers have developed strong preferences for this program offering and contribute regular load reductions under system peak conditions.

IX. Relationship to reliability-oriented and other demand response programs

PG&E believes there are important roles to be played by both reliability-oriented programs and dynamic pricing options and tariffs. As a general rule, much more certainty can be attached to the load drop available from reliability-oriented programs, while dynamic pricing options should afford customers additional advance notice and more flexibility in day-to-day operations.

1. What is the purpose of reliability-oriented demand response tariffs and programs such as interruptible rates and programs and air conditioning cycling?

Comment: Ideally, the reliability-oriented demand response tariffs and programs should provide customer load reduction resources that can be counted on with a great deal of certainty to help improve electric system reliability at times when conventional supply-side generation resources may not be sufficient to meet load, or when the system or parts thereof might otherwise be constrained.

Reliability-oriented DR tariffs will tend to offer a more dependable resource for load drop when compared to dynamic rates. Much DR can be obtained through hourly price signals that give customers an incentive to shift their loads off-peak. However, the levels to which load reductions occur through dynamic pricing may vary from day to day according to customer preferences and circumstances. Customers may feel they can save some money by shifting their load, and will often do so, but they may not feel the urgency to do so. Most reliability programs have punitive measures associated with them if load is not dropped by the participant. These measure help provide the program participant with a sense of urgency to curtail.

PG&E's A/C program is an exception to this general rule, as it is a reliability program but does not have a penalty for not dropping load. A fairly reliable amount of load relief is still expected through this program though because A/C load control devices are directly controlled by the utility, the program is designed to minimize customer discomfort, and it is being marketed for its social and environmental benefits, not just as a way to save money. Participants will presumably stay on the program and participate if they know that the program is only operated in an emergency.

Finally, dynamic pricing programs will always require a certain amount of advance notice to customers. For example, for the CPP and DBP programs, notice is given to customers to curtail on a day-ahead basis. This notice requirement reduces the utilities ability to call the programs for unforeseen conditions, such as a forced shutdown or a local emergency.

The Commission has recently provided additional guidance on its vision for the future development of the state's demand response programs. In an Assigned Commissioner's and Administrative Law Judge's Ruling dated October 1, 2007 (issued in R.07-01-041), the Energy Division's attachment entitled "Proposed Demand Response Goals" outlines the purposes of demand response tariffs and programs as follows:

- Customer Service: customers should be informed of time-variable electricity costs; detailed information about their energy use, and technologies that provide demand response, outage management, and power quality management.

- Optionality: customers should be able to select a range of DR tariff and program options. In addition, customers would participate in markets as a dispatchable resource.

- Investor-Owned Utility (IOU) Issues: IOUs should deploy DR resources as a portion of their overall procurement portfolio (target of 5% of peak demand by 2007) and as a portion of their reserve requirements.

- Technologies: All customers should be provided an advanced metering system and a choice to access their usage information via the internet, via on-site devices, or other means (including Home Area Networks or HAN). The state building code (Title 24) would provide a cost-effective opportunity to introduce demand response technologies for new construction and renovations.

2. To what extent can dynamic pricing rates provide the reliability benefits that are provided by reliability-oriented tariffs and programs?

Comment: Customer load reductions realized in response to new or expanded dynamic pricing programs might in the future afford some of the same benefits as the reliability-based programs, although this is more likely on a day-ahead rather than same-day basis. PG&E believes that prices would have to be taken to extremely high levels on a same-day basis before dynamic pricing rates could even begin to afford similar benefits to the existing reliability-oriented tariffs and programs. Moreover – at such pricing levels and under such short notice periods – the structure of a "reliability-oriented" dynamic pricing tariff might look similar to that of a traditional interruptible or curtailable tariff with steep non-compliance penalties.

Dynamic pricing rates can of course contribute to reducing the amount of system load when loads and prices are high. When fully implemented, load reductions of this type may be able to help avoid or reduce the likelihood emergency condition such as Stage 2 events or rotating outages. And dynamic rates can help provide an economic alternative to purchasing high price power. However, dynamic pricing programs are not a panacea. There is already evidence that customer receptiveness to voluntarily dropping load will decrease over the course of multiple day events such as severe heat storms. Such drop-offs are less likely to occur in the case of reliability-oriented programs. Also, reliability programs generally have much shorter response times for customer notification and dropping load, which means load reduction can be achieved more quickly and with much greater certainty.

3. Should customers have the option to simultaneously participate in dynamic pricing tariffs and interruptible or other reliability programs?

Comment: Yes. PG&E is supportive of allowing customers to participate in multiple programs if they choose to do so, provided that adequate measures are in place to avoid double payment for the same kilowatts of load reduction. This approach has been used successfully in the development of PG&E's existing portfolio of dynamic pricing options and demand response tariffs and programs.

Allowing customers to participate in multiple programs will also foster the development of new technologies such as Home Area Networks (HAN) and automated demand response equipment (such as AutoDR). As stated in the October 1, 2007 ACR issued in R.07-01-041:

- “HAN technology could also facilitate additional customer service benefits, such as the ability to control appliances remotely, detection and understanding of inefficient usage patterns and the ability to participate in direct load control programs.” (p. A-6)

- “AutoDR provides commercial and industrial customers with electronic, Internet-based price and reliability signals that are linked into the facility energy management control system (EMCS) and related whole-building controls. AutoDR price and reliability signals trigger automatic customer-programmed energy management and curtailment strategies. The AutoDR price and reliability signals can be used to automate response to dynamic pricing (CPP and RTP) as well as conventional interruptible and demand bid options.” (p. A-15)

4. When simultaneous participation is allowed, what rules are needed to minimize overpaying customers for demand reductions?

Comment: Generally, this question needs to be addressed on a case-by-case basis as each new tariff or program is developed. The underlying principle is fairly simple (multiple units of compensation should not be offered for the “same” kilowatts of demand reduction capability), but the details need to be addressed separately as each new program is introduced.

5. Should customers have the option to simultaneously participate in dynamic pricing tariffs and other price-responsive programs?

Comment: As with the reliability-based programs, PG&E is generally supportive of allowing for customer participation in multiple dynamic pricing options. However, PG&E cautions that some types of dynamic pricing options may allow for participation in only one program at a time.

X. Timing of tariff development and roll-out

Many of PG&E's existing dynamic pricing options and tariff programs can be further refined or developed during the course of PG&E's current GRC cycle. However, action on developing RTP tariffs should be deferred to PG&E's 2011 GRC, because publicly available day-ahead market prices are not yet available from the MRTU, and because a 12 to 18 month track record of prices from the MRTU should be reviewed before it can be determined how best to use this price information as inputs to the RTP tariffs.

1. When should time-differentiated tariffs be introduced for each customer class?

Comment: PG&E notes that certain forms of time-differentiated tariffs are already available for all customer classes, and additional options will become available as the AMI Project is deployed. PG&E looks to this proceeding as providing an opportunity for additional review and refinement of its existing pricing programs during the period leading up to its 2011 GRC, while also establishing a roadmap for the development of newer programs (such as RTP tariffs) in that GRC.

2. Does the detailed development of some time-differentiated tariffs need to wait until after the CAISO's MRTU is on-line?

Comment: Yes. As discussed in more detail in Sections II, III, and VI of these comments, PG&E believes that full RTP tariff development must wait until the MRTU is implemented and has been fully functional for a period of at least 12-18 months.

3. How does the meter installation schedule for small commercial and residential customers affect when tariffs should be introduced?

Comment: TOU pricing options are already available for nearly all of PG&E's residential and smaller commercial customers. More complex dynamic pricing tariffs and programs have begun to be developed and authorized for these customers, and are being made available to them as the new meters are installed.

4. Should customers be given time before the implementation of new time-differentiated tariffs so that customers may make technological and operational changes to benefit from the new tariffs?

Comment: As noted above, enrollment under certain types of new dynamic pricing tariffs and programs must wait until new meters are installed (and possibly other site-specific equipment, if authorized after PG&E files its upcoming Upgrade application). As a general matter, PG&E is supportive of making new tariffs and programs available to customers on a voluntary basis as soon as all necessary equipment is installed. However, to the extent that other programs are ordered to be implemented on a mandatory basis, PG&E would be supportive of anticipated customer requests that customers be given additional time for technological and operational changes prior to any mandatory assignment of customers to new tariffs or programs.

XI. Customer Education

The primary objectives for PG&E's customer education and marketing efforts will be to ensure that new programs are well-aligned with customer needs (as determined through customer research), and to actively help customers better understand their options, the changes taking place, and their potential for participation in dynamic pricing and demand response – so that customers can make informed choices and implement those options that yield the overall best result for their individual circumstances.

1. What type of education and marketing is necessary to help customers understand new dynamic tariff options?

Comment: PG&E believes that the type and frequency of education and marketing necessary to help customers understand new dynamic tariff options will depend upon the customer groups eligible for the programs, the complexity and structure of the programs, and whether the program is voluntary or mandatory. A variety of communication channels should be employed. These channels may include but would not be limited to one-on-one contact with account managers, customer newsletters, e-mail, website content, customer meetings and working through customer associations.

2. What type of education and marketing is necessary to help customers understand their options for responding to new dynamic tariffs?

Comment: Education and marketing programs necessary to help customers understand their options for responding to new dynamic tariff options also will depend on the customer groups eligible for the programs, the complexity and structure of the programs, and whether the program is voluntary or mandatory. A variety of communication channels should be employed. These channels may include but would not necessarily be limited to one-on-one contact with account managers, newsletters, customer's PG&E bill, e-mail, website content, customer meetings and working through customer associations.

3. How much money is needed for education and marketing?

Comment: The cost of acquiring customer participation in programs, and ensuring customers understand their options for responding to program incentives, will vary significantly depending upon the customer groups eligible for the programs, the complexity and features of the programs, and whether the program is voluntary or mandatory. As one example, the availability of a first year bill protection may significantly decrease the "acquisition cost" associated with recruiting customers for participation in a given program. Thus, it is far too early to begin gauging potential customer education and marketing costs for an unknown portfolio of new tariffs.

4. How should education and marketing be funded?

Comment: All customers should share in the education and marketing costs associated with dynamic pricing options, because all customers will benefit from the reduced procurement costs and improved system reliability which are the goals of dynamic pricing.

5. How should customer bills be designed to communicate information about dynamic rates?

Comment: The customer bill may be used both to communicate information about the availability of dynamic pricing options and to communicate the way charges are incurred by a customer enrolled in a dynamic pricing program. PG&E is currently redesigning customer bills. The proposed redesigned bill will, among other things, include graphs of average daily usage of gas and electricity over the most recent one-year period. Over time, PG&E will try to continue to update and enhance customer bill information in response to customer preferences.

6. What information should be available on the Internet?

Comment: PG&E's web site will at a minimum include information about:

- PG&E's pricing options, including demand response programs;
- Real-time market prices including, when it becomes available on a regular basis, links to the real-time market prices published by the CEC or the CAISO;
- Metering technology and other enabling technologies currently available to and planned for PG&E's customers;
- Customer-specific interval metering data for large commercial and industrial customers, which is already currently available; and
- Customer-specific interval metering data for small commercial and residential customers, which will become available with the rollout of SmartMeter™ technology.

7. How should CPP events and dynamic prices be communicated to customers?

Comment: If a CPP event occurs, customers are notified using PG&E's web site, e-mail or alphanumeric pager. Some customers also use an "energy information orb". See below for a discussion of SmartMeter-related technologies that may expand the possible options for communicating dynamic prices to customers.

8. Are there opportunities for customer education and dynamic load information to elicit significant demand response even in the absence of a dynamic pricing tariff?

Comment: There is evidence that customer education, communication and marketing can have significant impacts on demand response even absent a dynamic pricing program. Customer communications and marketing have the potential to motivate changes in customer behavior and inform customers of demand response options, SmartRate and other existing programs. Further, the demand response achieved through education and marketing may potentially be more cost effective than creating and implementing a dynamic pricing tariff for residential and small commercial customers. Additional customer research in this area should be considered and provided for as dynamic rate design options and other programs are more fully developed.

XII. Enabling Technology

PG&E will be supportive of helping customers choose appropriate enabling technology for automated demand response participation, and will continue to monitor developments in the emerging market for such technologies.

1. In addition to interval meters, do the utilities need to offer enabling technologies to facilitate customer response to dynamic pricing?

Comment: PG&E anticipates making all currently envisioned dynamic tariffs and pricing options available to customers without requiring enabling technology as a precondition for program participation. However, offering enabling technologies could lower possible barriers to participation as perceived by some customers, making it possible to increase the numbers of customers choosing these tariffs and also increasing the ability of many customers to respond effectively when the programs are activated. With enabling technology in place, customers might be able to effectively pre-select specified loads at their premise for automated response to customer-selected pricing changes. While the availability of such equipment may be somewhat limited at present, this can be anticipated to improve in the relatively near future – affording customers new opportunities to take effective advantage of those dynamic pricing options they find most suitable for their own electric usage.

PG&E will continue to monitor the development of appropriate load control enabling technologies for all customer classes, and is committed to maintaining a high degree of inter-operability between equipment deployed under the AMI project and customer load control equipment. For example, PG&E is currently preparing a project Upgrade application which would (among other things) add the capability to measure usage at short time intervals (as little as 5-10 seconds) and provide customers with new opportunities for nearly real-time information about their own usage together with the ability to use this information as inputs for automated load control devices as such devices become increasingly available.

2. Will the introduction of dynamic pricing create a demand for enabling technologies that will drive the marketplace, even without additional subsidies or regulations?

Comment: PG&E believes the market for enabling technologies is poised for significant growth, given the increasing penetration of real-time output devices as additional utilities implement AMI projects. On-site energy management systems such as energy information displays and smart thermostats are becoming more cost-effective and customer load information for these devices will be available on a near real-time basis, creating additional opportunities for energy management system providers to develop this emerging market.

3. Will the introduction of dynamic pricing provide customers an incentive to invest in permanent load shifting technologies?

Comment: The introduction of dynamic pricing and further development of improved energy management technologies for homes and businesses should provide new opportunities and incentives for customers to invest in technology that will help them reduce their energy costs while maintaining adequate comfort levels and meet operational requirements. This type of load response may take a variety of forms, including both permanent shifting of some types of loads and also more dynamic load reductions on smaller numbers of system peak days.

4. Should the CPUC increase technical assistance and technical incentives in conjunction with new rate options to subsidize enabling technologies?

Comment: PG&E has previously joined in making recommendations for these types of incentives for new programs on a case-by-case basis, and is generally supportive of providing additional incentives to help advance the development and adoption of cost-effective enabling technologies.

5. Should enabling technologies be encouraged in other ways, such as through California Energy Commission standards?

Comment: PG&E believes the market for enabling technologies is still at a relatively early stage of development – one that is still too early for the adoption of formal standards, and a stage at which it is probably best to monitor market development rather than attempt to guide it.

6. What additional technologies, if any, are necessary to communicate dynamic prices to customers?

Comment: PG&E believes active outreach programs will help customers to make informed choices based on the best match between their own business operations or comfort levels and new rate program offerings. This approach should yield greater demand response results over the long term, as measured both in terms of total demand reductions achieved and in terms of overall customer satisfaction with demand response program offerings.

CERTIFICATE OF SERVICE BY ELECTRONIC MAIL

I, the undersigned, state that I am a citizen of the United States and am employed in the City and County of San Francisco; that I am over the age of eighteen (18) years and not a party to the within cause; and that my business address is Pacific Gas and Electric Company, Law Department B30A, Post Office Box 7442, San Francisco, CA 94120.

On the 5th day of October 2007, I served a true copy of:

COMMENTS OF PACIFIC GAS AND ELECTRIC COMPANY ON QUESTIONS RAISED IN THE AUGUST 22, 2007, SUPPLEMENTAL SCOPING MEMO AND ASSIGNED COMMISSIONER'S RULING

by electronic service to the e-mail addresses for the parties listed on the official service list for Application No. 06-03-005.

I certify and declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct.

Executed on this 5th day of October, 2007 at San Francisco, California.

/s/
PAMELA J. DAWSON-SMITH

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ALJ Assigned: David K. Fukutome on March 16, 2006

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